Generator Protection Application Guide

Basler Electric

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Introduction

This guide was developed to assist in the selection of relays to protect a generator. The purpose of each relay is described and related to one or more power system configurations. A large number of relays is available to protect for a wide variety of conditions. These relays protect the generator or prime mover from damage. They also protect the external power system or the processes it supplies. The basic principles offered here apply equally to individual relays and to multifunction numeric packages.

The engineer must balance the expense of applying a particular relay against the consequences of losing a generator. The total loss of a generator may not be catastrophic if it represents a small percentage of the investment in an installation. However, the impact on service reliability and upset to loads supplied must be considered. Damage to and loss of product in continuous processes can represent the dominating concern rather than the generator unit. Accordingly, there is no standard solution based on the MW rating. However, it is rather expected that a 500kW, 480V, standby reciprocating engine will have less protection than a 400MW base load steam turbine unit. One possible common dividing point is that the extra CTs needed for current differential protection are less commonly seen on generators less than 2MVA, generators rated less than 600V, and generators that are never paralleled to other generation.

This guide simplifies the process of selecting relays by describing how to protect against each type of fault or abnormal condition. Then, suggestions are made for what is considered to be minimum protection as a baseline. After establishing the baseline, additional relays, as described in the section on Extended Protection, may be added.

The subjects covered in this guide are as follows:

- Ground Fault (50/51-G/N, 27/59, 59N, 27-3N, 87N)
- Phase Fault (51, 51V, 87G)
- Backup Remote Fault Detection (51V, 21)
- Reverse Power (32)
- Loss of Field (40)
- Thermal (49)
- Fuse Loss (60)
- Overexcitation and Over/Undervoltage (24, 27/59)
- Inadvertent Energization (50IE, 67)
- Negative Sequence (46, 47)
- Off-Frequency Operation (81O/U)
- Sync Check (25) and Auto Synchronizing (25A)
- Out of Step (78)
- Selective and Sequential Tripping
- Integrated Application Examples
- Application of Multifunction Numerical Relays
- Typical Settings
- Basler Electric Products for Protection

The references listed on Page 22 provide more background on this subject. These documents also contain Bibliographies for further study.

Ground Fault Protection

The following information and examples cover three impedance levels of grounding: low, medium, and high. A low impedance grounded generator refers to a generator that has zero or minimal impedance applied at the Wye neutral point so that, during a ground fault at the generator HV terminals, ground current from the generator is approximately equal to 3 phase fault current. A medium impedance grounded generator refers to a generator that has substantial impedance applied at the wye neutral point so that, during a ground fault, a reduced but readily detectable level of ground current, typically on the order of 100-500A, flows. A high impedance grounded generator refers to a generator with a large grounding impedance so that, during a ground fault, a nearly undetectable level of fault current flows, necessitating ground fault monitoring with voltage based (e.g., 3rd harmonic voltage monitoring and fundamental frequency neutral voltage shift monitoring) relays. The location of the grounding, generator neutral(s) or transformer, also influences the protection approach.

The location of the ground fault within the generator winding, as well as the grounding impedance, determines the level of fault current. Assuming that the generated voltage along each segment of the winding is uniform, the prefault line-ground voltage level is proportional to the percent of winding between the fault location and the generator neutral, V_{FG} in Fig. 1. Assuming an impedance grounded generator where ($Z_{0, SOURCE}$ and Z_N)>>$Z_{WINDING}$, the current level is directly proportional to the distance of the point from the generator neutral [Fig. 1(a)], so a fault 10% from neutral produces 10% of the current that flows for a fault on the generator terminals. While the current level drops towards zero as the neutral is approached, the insulation stress also drops, tending to reduce the probability of a fault near the neutral. If a generator grounding impedance is low relative to the generator winding impedance or the system ground impedance is low, the fault current decay will be non-linear. For I_1 in Fig. 1, lower fault voltage is offset by lower generator winding resistance. An example is shown in Fig. 1(b).

The generator differential relay (87G) may be sensitive enough to detect winding ground faults with low-impedance grounding per Fig. 2. This would be the case if a solid generator-terminal fault produces approximately 100% of rated current. The minimum pickup setting of the differential relays (e.g., Basler BE1-CDS220 or BE1-87G, Table 2) should be adjusted to sense faults on as much of the winding as possible. However, settings below 10% of full load current (e.g., 0.4A for 4A full load current) carry increased risk of misoperation due to transient CT saturation during external faults or during step-up transformer energization. Lower pickup settings are recommended only with high-quality CTs (e.g., C400) and a good CT match (e.g., identical accuracy class and equal burden).

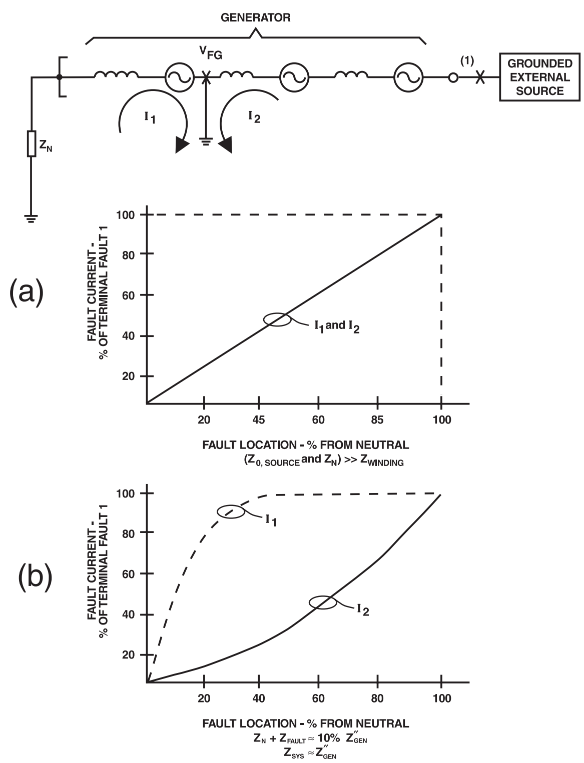


FIGURE 1. EFFECTS OF FAULT LOCATION WITHIN GENERATOR ON CURRENT LEVEL.

If 87G relaying is provided per Fig. 2, relay 51N (e.g., Basler relays per Table 2) backs up the 87G, as well as external relays. If an 87G is not provided or is not sufficiently sensitive for ground

faults, then the 51N provides the primary protection for the generator. The advantage of the 87G is that it does not need to be delayed to coordinate with external protection; however, delay is required for the 51N. One must be aware of the effects of transient DC offset induced saturation on CTs during transformer or load energization with respect to the high speed operation of 87G relays. Transient DC offset may induce CT saturation for many cycles (likely not more than 10), which may cause false operation of an 87G relay. This may be addressed by not block loading the generator, avoiding sudden energization of large transformers, providing substantiallly overrated CTs, adding a very small time delay to the 87G trip circuit, or setting the relay fairly insensitively.

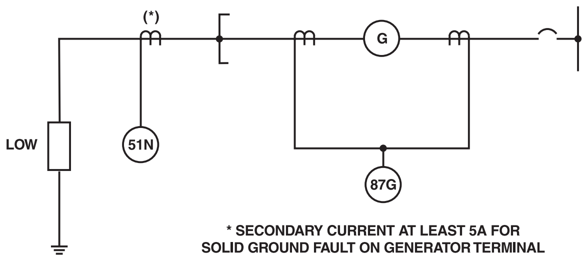


FIGURE 2. GROUND-FAULT RELAYING - GENERATOR LOW-IMPEDANCE GROUNDING.

The neutral CT should be selected to produce a secondary current of at least 5A for a solid generator terminal fault, providing sufficient current for a fault near the generator neutral. For example, if a terminal fault produces 1000A in the generator neutral, the neutral CT ratio should not exceed 1000/5. For a fault 10% from the neutral and assuming I_1 is proportional to percent winding from the neutral, the 51N current will be 0.5A, with a 1000/5 CT.

Fig. 3 shows multiple generators with the transformer providing the system grounding. This arrangement applies if the generators will not be operated with the transformer out of service. The scheme will lack ground fault protection before generator breakers are closed. The transformer could serve as a step-up as well as a grounding transformer function. An overcurrent relay 51N or a differential relay 87G provides the protection for each generator. The transformer should produce a ground current of at least 50% of generator rated current to provide about 95% or more winding coverage.

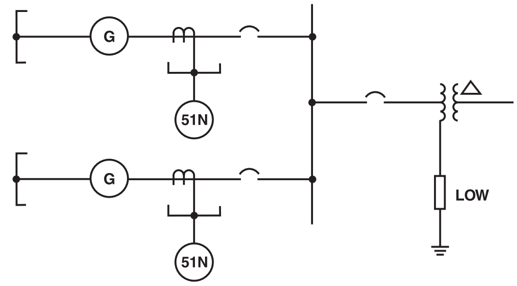


FIGURE 3. SYSTEM GROUNDED EXTERNALLY WITH MULTIPLE GENERATORS.

Fig. 4 shows a unit-connected arrangement (generator and step-up transformer directly connected with no low-side breaker), using high-resistance grounding. The grounding resistor and voltage relays are connected to the secondary of a distribution transformer. The resistance is normally selected so that the reflected primary resistance is approximately equal to one-third of the single phase line-ground capacitive reactance of the generator, bus, and step-up transformer. This will limit fault current to 5-10A primary. Sufficient resistor damping prevents ratcheting up of the sound-phase voltages in the presence of an intermittent ground. The low current level minimizes the possibility of sufficient iron damage to require re-stacking. Because of the low current level, the 87G relay will not operate for single-phase ground faults.

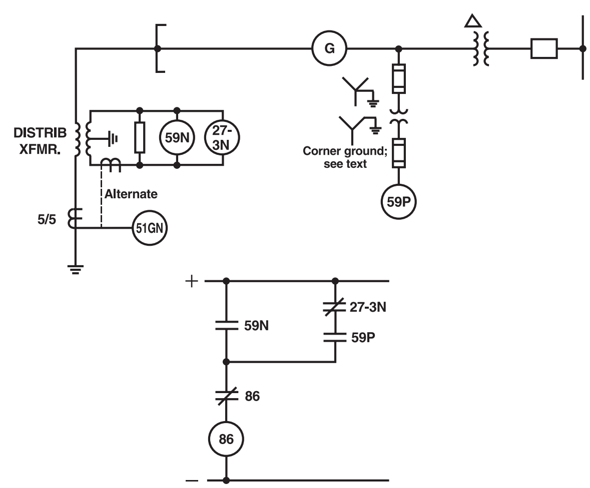


FIGURE 4. UNIT-CONNECTED CASE WITH HIGH-RESISTANCE GROUNDING.

Protection in Fig. 4 consists of a 59N overvoltage relay and a 27-3N third-harmonic undervoltage relay (e.g., Basler relays per Table 2). As shown

in Fig. 5, a ground fault at the generator high voltage bushings elevates the sound phase line to ground voltages to a nominal 173% of normal line to neutral voltages. Also, the neutral to ground voltage will rise to the normal phase-ground voltage levels. The closer the ground fault is to the generator neutral, the less the neutral to ground voltage will be. One method to sense this neutral shift is with the 59N relay (Fig. 4) monitoring the generator neutral. The 59N will sense and protect the generator for ground faults over about 95% of the generator winding. The selected 59N (Basler relays per Table 2) relay should be selected so as to not respond to third harmonic voltage produced during normal operation. The 59N will not operate for faults near the generator neutral because of the reduced neutral shift during this type of fault.

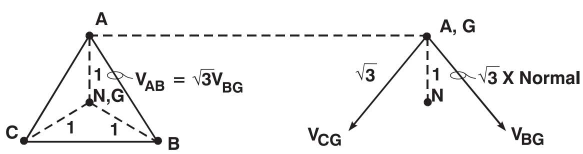


FIGURE 5. NEUTRAL SHIFT DURING GROUND FAULT ON HIGH IMPEDANCE GROUNDED SYSTEM.

Faults near the generator neutral may be sensed with the 27-3N. When high impedance grounding is in use, a detectable level of third harmonic voltage will usually exist at the generator neutral, typically 1-5% of generator line to neutral fundamental voltage. The level of third harmonic is dependent on generator design and may be very low in some generators (a 2/3 pitch machine will experience a notably reduced third harmonic voltage). The level of harmonic voltage will likely decrease at lower excitation levels and lower load levels. During ground faults near the generator neutral, the third harmonic voltage in the generator neutral is shorted to ground, causing the 27-3N to drop out (Fig. 6). It is important that the 27-3N have high rejection of fundamental frequency voltage.

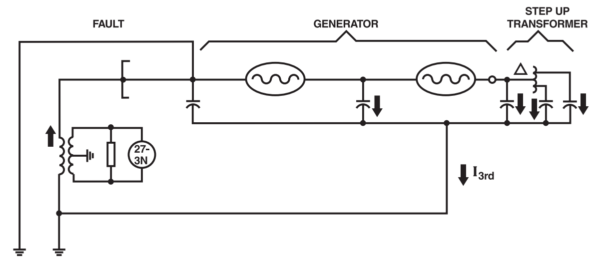


FIGURE 6. GROUND FAULT NEAR GENERATOR NEUTRAL REDUCES THIRD-HARMONIC VOLTAGE IN GENERATOR NEUTRAL, DROPPING OUT 27-3N.

The 27-3N performs a valuable monitoring function aside from its fault detection function; if the grounding system is shorted or an open occurs, the 27-3N drops out.

The 59P phase overvoltage relay in Fig. 4 supervises the 27-3N relay, so that the 86 lockout relay can be reset when the generator is out of service; otherwise, the field could not be applied. Once the field is applied and the 59P operates, the 27-3N protection is enabled. The 59P relay should be set for about 90% of rated voltage. An “a” contact of the unit breaker can be used instead of the 59P relay to supervise 27-3N tripping. Blocking the 27-3N until some level of forward power exists also has been done. However, use of the 59P relay allows the 27-3N to provide protection prior to synchronization (i.e., putting the unit on line), once the field has been applied.

In order to provide 100% stator winding coverage, the undervoltage (27-3N) and overvoltage (59N) settings should overlap. For example, if a generator-terminal fault produces 240V, 60 Hz across the neutral voltage relay (59N), a 1V pickup setting (a fairly sensitive setting) would allow all but the last (1/240)*100 = 0.416% of the winding to be covered by the overvoltage function. If 20V third harmonic is developed across the relay prior to a fault, a 1V third-harmonic drop-out setting would provide dropout for a fault up to (1/20)*100= 5% from the neutral. Setting the 59N pickup too low or the 27N dropout too low may result in operation of the ground detection system during normal operating conditions. The third harmonic dropout level may be hardest to properly set, since its level is dependent on machine design and generator excitation and load levels. It may be advisable to

measure third harmonic voltages at the generator neutral during unloaded and loaded conditions prior to selecting a setting for the 27-3N dropout. In some generators, the third harmonic at the neutral may become almost unmeasurably low during low excitation and low load levels, requiring blocking the 27-3N tripping mode with a supervising 32 underpower element when the generator is running unloaded.

There is also some level of third harmonic voltage present at the generator high voltage terminals. A somewhat predictable ratio of $(V_{3RD\text{-}GEN.HV.TERM})/(V_{3RD\text{-}GEN.NEUTRAL})$ will exist under all load conditions, though this ratio may change if loading can induce changes in third harmonic voltages. A ground fault at the generator neutral will change this ratio, and this ratio change is another means to detect a generator ground fault. Two difficulties with this method are: problems with developing means to accurately sense low third harmonic voltages at the generator high voltage terminals in the presence of large fundamental frequency voltages, and problems with dealing with the changes in third harmonic ratio under some operating conditions.

If the 59N relay is only used for alarming, the distribution transformer voltage ratio should be selected to limit the secondary voltage to the maximum continuous rating of the relay. If the relay is used for tripping, the secondary voltage could be as high as the relay's ten-second voltage rating. Tripping is recommended to minimize iron damage for a winding fault as well as minimizing the possibility of a multi-phase fault.

Where wye-wye voltage transformers (VTs) are connected to the machine terminals, the secondary VT neutral should not be grounded in order to avoid operation of 59N for a secondary ground fault. Instead, one of the phase leads should be grounded (i.e., "corner ground"), leaving the neutral to float. This connection eliminates any voltage across the 59N relay for a secondary phase-ground fault. If the VT secondary neutral is grounded, a phase-ground VT secondary fault pulls little current, so the secondary fuse sees little current and does not operate. The fault appears to be a high impedance phase to ground fault as seen by the generator neutral shift sensing relay (59N), leading to a generator trip. Alternatively, assume that the VT corner (e.g., phase A) has been grounded. If phase B or C fault to ground, the fault will appear as a phase-phase fault, which will pull high secondary currents and will clear the secondary fuse rapidly and prevent 59N operation. A neutral to ground fault will tend to operate the 59N, but this is a low likelihood event. An isolation VT is required if the generator VTs would otherwise be galvanically connected to a set of neutral-grounded VTs. Three wye VTs should be applied where an iso-phase bus (phase conductors separately enclosed) is used to protect against phase-phase faults on the generator terminals.

The 59N relay in Fig. 4 is subject to operation for a ground fault on the wye side of any power transformer connected to the generator. This voltage is developed even though the generator connects to a delta winding because of the transformer inter-winding capacitance. This coupling is so small that its effect can ordinarily be ignored; however, this is not the case with the 59N application because of the very high grounding resistance. The 59N overvoltage element time delay allows the relay to override external-fault clearing.

The Basler BE1-GPS100, BE1-951, BE1-1051, and BE1-59N relays contain the required neutral overvoltage (59N), undervoltage (27-3N), and phase overvoltage (59P) units.

Fig. 4 shows a 51GN relay as a second means of detecting a stator ground fault. The use of a 51GN in addition to the 59N and 27-3N is readily justified, since the most likely fault is a stator ground fault. An undetected stator ground fault would be catastrophic, eventually resulting in a multiphase fault with high current flow, which persists until the field flux decays (e.g., for 1 to 4s). The CT shown in Fig. 4 could be replaced with a CT in the secondary of the distribution transformer, allowing use of a CT with a lower voltage rating. However, the 51GN relay would then be inoperative if the distribution transformer primary becomes shorted. The CT ratio for the secondary-connected configuration should provide for a relay current about equal to the generator neutral current (i.e., 5:5 CT). In either position, the relay pickup should be above the harmonic current flow during normal operation. (Typically harmonic current will be less than 1A but the relay may be

set lower if the relay filters harmonic currents and responds only to fundamental currents.) Assuming a maximum fault current of 8A primary in the neutral and a relay set to pick up at 1A primary, 88% of the stator winding is covered. As with the 59N relay, the 51GN delay will allow it to override clearing of a high-side ground fault. An instantaneous overcurrent element can also be employed, set at about three times the time-overcurrent element pickup, although it may not coordinate with primary vt fuses that are connected to the generator terminals.

Multiple generators, per Fig. 7, can be high-resistance grounded, but the 59N relays will not be selective. A ground fault anywhere on the generation bus or on the individual generators will be seen by all 59N relays, and the tendency will be for all generators to trip. The 51N relay, when connected to a flux summation CT, will provide selective tripping if at least three generators are in service. In this case, the faulted generator 51N relay will then see more current than the other 51N relays. The proper 51N will operate before the others because of the inverse characteristic of the relays. Use of the flux summation CT is limited to those cases where the CT window can accommodate the three cables. Fault currents are relatively low, so care must be exercised in selecting appropriate nominal relay current level (e.g., 5A vs. 1A) and CT ratio. For example, with a 30A fault level and a 50 to 5A CT, a 1A nominal 51N with a pickup of 0.1A might be used. With two generators, each contributing 10A to a terminal fault in a third generator, the faulted-generator 51N relay sees 2*10/(50/5) = 2A. Then the relay protects down to (0.1/2)*100 = 5% from the neutral.

When feeder cables are connected to the generator bus, the additional capacitance dictates a much lower level of grounding resistance than achieved with a unit-connected case. A lower resistance is required to minimize transient overvoltages during an arcing fault.

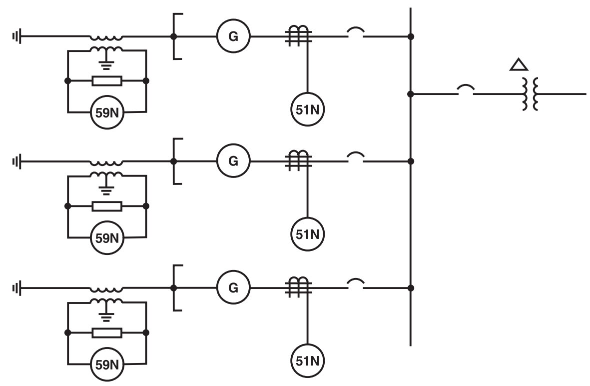


FIGURE 7. 59N RELAY OPERATION WITH MULTIPLE UNITS WILL NOT BE SELECTIVE; 51N RELAYS PROVIDE SELECTIVE PROTECTION IF AT LEAST THREE GENERATORS ARE IN SERVICE.

Ground differential (Fig. 8) is a good method to sense ground faults on low and medium impedance grounded units. It would more commonly be seen on generators that have the CTs required for phase differential relaying. In Fig. 8, the protective function is labeled 87N, but the Basler BE1-CDS220 or the BE1-67N is applied. The BE1-CDS220 approach is more applicable to low and medium impedance grounded generators with ground faults as low as 50% of phase fault current. The BE1-67N approach is more applicable to medium impedance generators with low ground fault current levels. The BE1-CDS220 is limited in sensitivity to ground faults in excess of 10% of the phase CT tap setting, but the use of the auxiliary CT in the BE1-67N approach allows for amplification of the ground current in the phase CTs, yielding increased sensitivity. Whichever approach is used, an effort should be made to select relay settings to trip for faults as low as 10% of maximum ground fault current levels. During external phase faults, considerable 87N operating current can occur when there is dissimilar saturation of the phase CTs due to high AC current or due to transient DC offset effects, while the generator neutral current still will be zero, assuming balanced conductor impedances to the fault. One method to compensate for transient CT saturation is to have sufficient delay in the relay to ride through external high-current two-phase-ground faults.

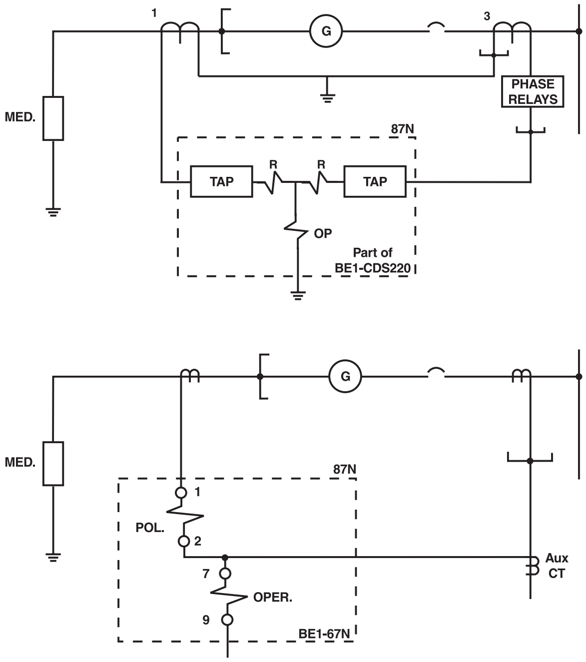


FIGURE 8. MEDIUM-LEVEL GROUNDING WITH 87N GROUND DIFFERENTIAL PROTECTION.

Phase-Fault Protection

Fig. 9 shows a simple means of detecting phase faults, but clearing is delayed, since the 51 relay must be delayed to coordinate with external devices. Since the 51 relay operates for external faults, it is not generator zone selective. It will operate for abnormal external operating conditions such as remote faults that are not properly cleared by remote breakers. The 51 pickup should be set at about 175% of rated current to override swings due to a slow-clearing external fault, the starting of a large motor, or the re-acceleration current of a group of motors. Energization of a transformer may also subject the generator to higher than rated current flow.

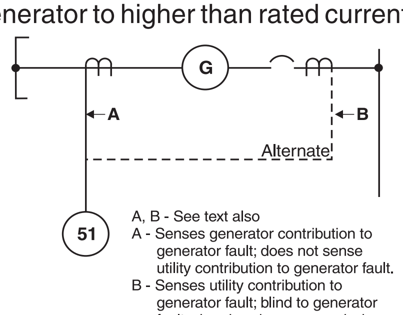


FIGURE 9. PHASE-OVERCURRENT PROTECTION (51) MUST BE DELAYED TO COORDINATE WITH EXTERNAL RELAYS.

Fig. 10 shows an example of generator current decay for a 3 phase fault and a phase-phase fault. For a 3 phase fault, the fault current decays below the pickup level of the 51 relay in approximately one second. If the time delay of the 51 can be selectively set to operate before the current drops to pickup, the relay will provide 3 phase fault protection. The current does not decay as fast for a phase-phase or a phase-ground fault and, thereby, allows the 51 relay more time to trip before current drops below pickup. Fig. 10 assumes no voltage regulator boosting, although the excitation system response time is unlikely to provide significant fault current boosting in the first second of the fault. It also assumes no voltage regulator dropout due to loss of excitation power during the fault. If the generator is loaded prior to the fault, prefault load current and the associated higher excitation levels will provide the fault with a higher level of current than indicated by the Fig. 10 curves. An estimate of the net fault current of a pre-loaded generator is a superposition of load current and fault current without pre-loading. For example, assuming a pre-fault 1pu rated load at 30 degree lag, at one second the 3 phase fault value would be 2.4 times rated, rather than 1.75 times rated ($1@30°+1.75@90°=2.4@69°$). Under these circumstances, the 51 relay has more time to operate before current decays below pickup.

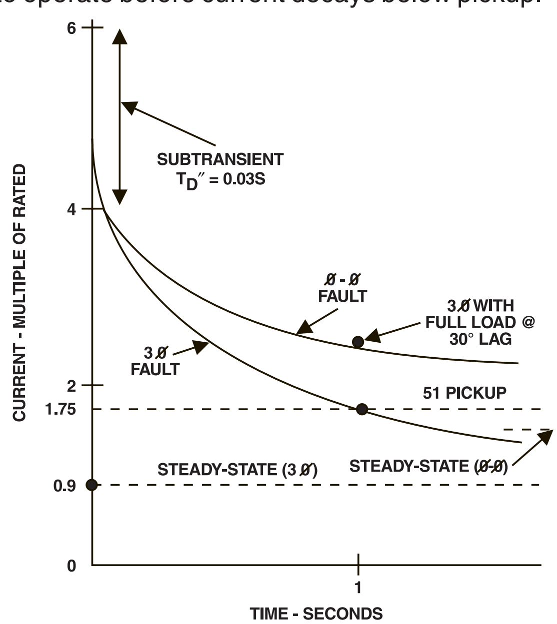


FIGURE 10. GENERATOR FAULT CURRENT DECAY EXAMPLE FOR 3 PHASE AND PHASE-PHASE FAULTS AT GENERATOR TERMINALS - WITH NO REGULATOR BOOSTING OR DROPOUT DURING FAULT AND NO PREFAULT LOAD.

Figure 9 shows the CTs on the neutral side of the generator. This location allows the relay to sense internal generator faults but does not sense fault current coming into the generator from the external system. Placing the CT on the system side of the generator introduces a problem of the relay not seeing a generator internal fault when the main breaker is open and when running the generator isolated from other generation or the utility. If an external source contributes more current than does the generator, using CTs on the generator terminals, rather than neutral-side CTs, will increase 51 relay sensitivity to internal faults due to higher current contribution from the external source; however, the generator is unprotected should a fault occur with the breaker open or prior to synchronizing.

Voltage-restrained or voltage-controlled time-overcurrent relays (51VR, 51VC) may be used as shown in Fig. 11 to remove any concerns about ability to operate before the generator current drops too low. The voltage feature allows the relays to be set below rated current. The Basler BE1-951, BE1-1051, BE1-GPS100, and BE1-51/27R voltage restrained approach causes the pickup to decrease with decreasing voltage. For example, the relay might be set for about 175% of generator rated current with rated voltage applied; at 25% voltage the relay picks up at 25% of the relay setting (1.75*0.25=0.44 times rated). The Basler BE1-951, BE1-GPS, and BE1-51/27C voltage controlled approach inhibits operation until the voltage drops below a preset voltage. It should be set to function below about 80% of rated voltage with a current pickup of about 50% of generator rated. Since the voltage-controlled type has a fixed pickup, it can be more readily coordinated with external relays than can the voltage-restrained type. The voltage-controlled type is recommended since it is easier to coordinate. However, the voltage-restrained type will be less susceptible to operation on swings or motor starting conditions that depress the voltage below the voltage-controlled undervoltage unit dropout point.

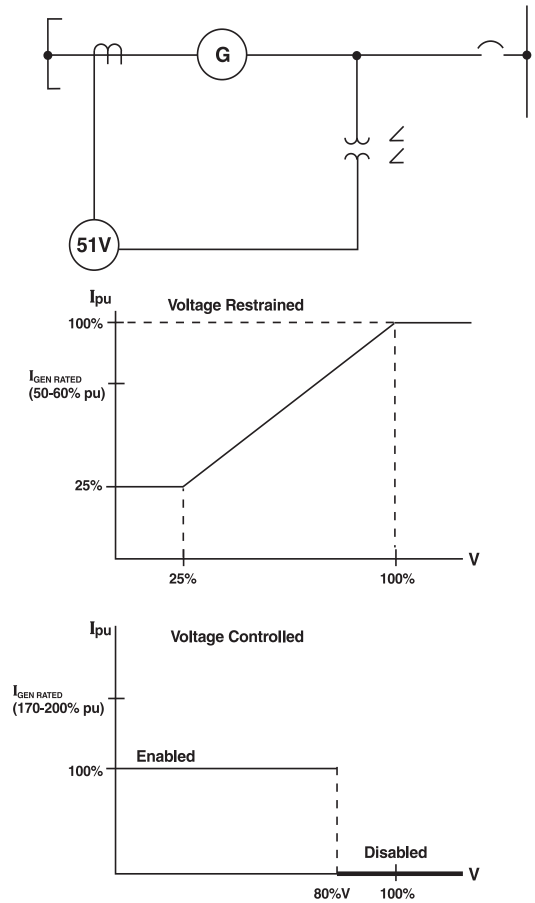


FIGURE 11. VOLTAGE-RESTRAINED OR VOLTAGE-CONTROLLED TIME-OVERCURRENT PHASE FAULT PROTECTION.

Fig. 12 eliminates concerns about the decay rate of the generator current by using an instantaneous overcurrent relay (50) on a flux summation CT, where the CT window can accommodate cable from both sides of the generator. The relay does not respond to generator load current nor to external fault conditions. The instantaneous overcurrent relay (50) acts as a phase differential relay (87) and provides high-speed sensitive protection. This approach allows for high sensitivity. For instance, it would be feasible to sense fault currents as low as 1-5% of generator full load current. It is common to use 50/5 CTs and to use 1A nominal relaying. A low CT ratio introduces critical saturation concerns (e.g., a 5,000A primary fault may try to drive a 500A secondary on a 50/5 CT). The CT burden must be low to prevent saturation of the CT during internal faults that may tend to highly overdrive the CT secondary. The 51 relay shown in Fig. 12 is applied for

back-up of external faults and as back-up for the 50 relay.

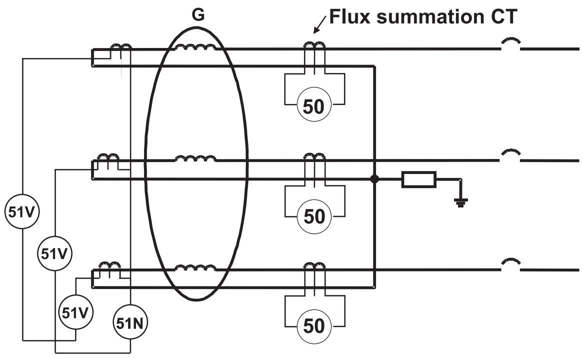


FIGURE 12. FLUX SUMMATION RELAY (50) PROVIDES SENSITIVE, HIGH-SPEED, SELECTIVE DIFFERENTIAL PROTECTION (87).

The 87G relay in Fig. 13 is connected to respond to phase differential currents from two sets of CTs. In some applications it may include a unit differential that includes the step-up transformer. In contrast to a 51 or 51V relay that monitors only one CT, the 87G relay responds to both the generator and external contributions to a generator fault. Because of the differential connection, the relay is immune, except for transient CT saturation effects, to operation due to generator load flow or external faults and, therefore, can provide sensitive, high speed protection. While the CTs must be of the same ratio, they do not need to be matched in performance, but the minimum pickup of the Basler BE1-CDS220 or BE1-87G must be raised as the degree of performance mismatch increases. (See the BE1-CDS220 and BE1-87G instruction manuals for specifics on settings.) A minimum pickup of 0.1 times tap (CDS220) or 0.4A (87G) is representative of a recommended setting for a moderate mismatch in CT quality and burden. Fig. 13 also shows 51V relays to back up the 87G and external relays and breakers.

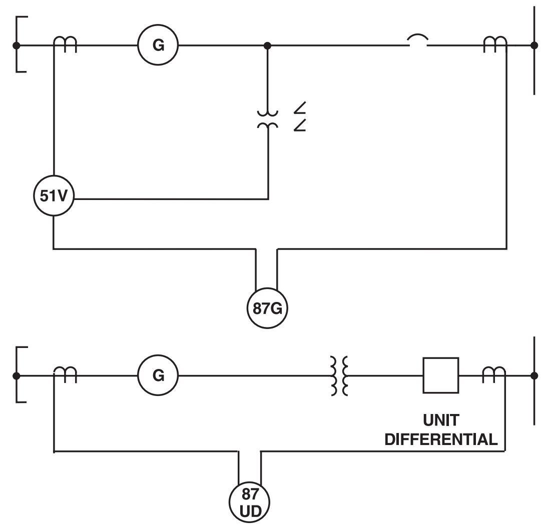


FIGURE 13. 87G PROVIDES SENSITIVE, HIGH-SPEED COVERAGE; 51V PROVIDES BACK-UP FOR 87G AND FOR EXTERNAL RELAYS. 87G MAY WRAP STEP UP TRANSFORMER (UNIT DIFFERENTIAL).

Another means to detect external faults is with impedance relaying. Impedance relaying divides current by voltage on a complex number plane (Z = V/I using phasor math) (Figs. 14, 15). Such relaying is inherently faster than time-overcurrent relaying. In the most common format of impedance relaying, the tripping zone is the area covered by a "mho" circle on the R-X plane that has a diameter from the origin (the CT, VT location) to some remote set point on the R-X plane. If a fault impedance falls within the zone, the relay trips. Multiple zones may be used, with delays on all zones as appropriate for coordinating with line relays. Impedance relaying is highly directional. In Fig. 14, however, because the CT is on the neutral rather than at the VT, the relay will see faults both in the generator and in the remote system.

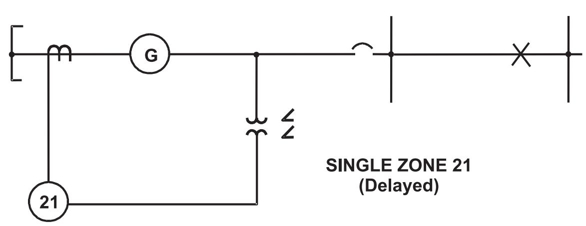


FIGURE 14. IMPEDANCE RELAY, LOOKING FOR GENERATOR AND REMOTE LINE FAULTS.

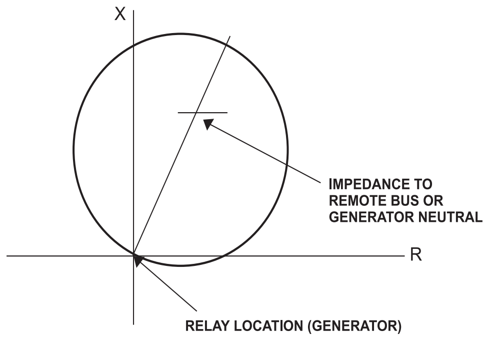


FIGURE 15. IMPEDANCE RELAY, LOOKING FOR REMOTE LINE FAULTS.

Reverse Power Protection

The reverse-power relay (32) in Fig. 16 senses real power flow into the generator, which will occur if the generator loses its prime-mover input. Since the generator is not faulted, CTs on either side of the generator would provide the same measured current.

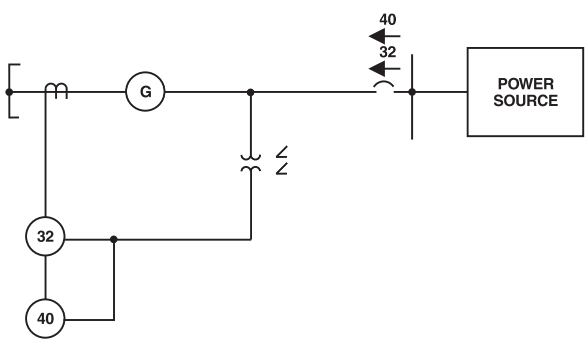


FIGURE 16. ANTI-MOTORING (32), LOSS-OF-FIELD (40), PROTECTION.

In a steam-turbine, the low pressure blades will overheat with the lack of steam flow. Diesel and gas-turbine units draw large amounts of motoring power, with possible mechanical problems. In the case of diesels, the hazard of a fire and/or explosion may occur due to unburnt fuel. Therefore, anti-motoring protection is recommended whenever the unit may be connected to a source of motoring power. Where a non-electrical type of protection is in use, as may be the case with a steam turbine unit, the 32 relay provides a means of supervising this condition to prevent opening the generator breaker before the prime mover has shut down. Time delay should be set for about 5-30 seconds, providing enough time for the controls to pick up load upon synchronizing when the generator is initially slower than the system.

Since motoring can occur during a large reactive-power flow, the real power component needs to be measured at low power factors. The BE1-32R measures real power down to 0.1 pf. The BE1-951, BE1-1051, and BE1-GPS measure real power down to below 0.01 pf, depending on current magnitude.

Fig. 17 shows the use of two reverse-power relays: 32-1 and 32-2. The 32-1 relay supervises the generator tripping of devices that can wait until the unit begins to motor. Overspeeding on large steam-turbine units can be prevented by delaying main and field breaker tripping until motoring occurs for non-electrical and selected electrical conditions (e.g., loss-of-field and overtemperature). Relay 32-1 should be delayed maybe 3 seconds, while relay 32-2 should be delayed by maybe 20 seconds. Time delay would be based on generator response during generator power swings. Relay 32-2 trips directly for cases of motoring that were not initiated by lockout relay 86NE — e.g., governor control malfunction.

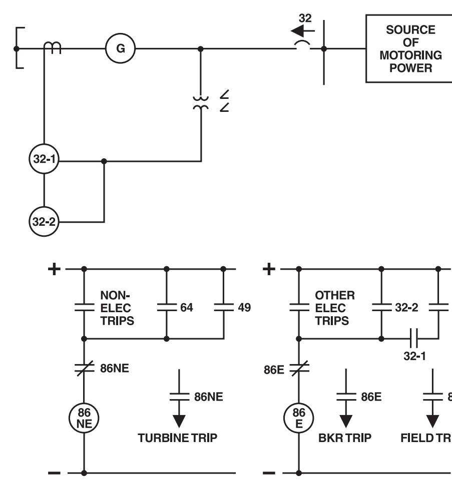


FIGURE 17. REVERSE-POWER RELAY 32-1 PREVENTS LOAD REJECTION BEFORE PRIME MOVER SHUTDOWN FOR SELECTED TRIPS; RELAY 32-2 OPERATES IF MOTORING IS NOT ACCOMPANIED BY AN 86NE OPERATION.

Loss-of-Field Protection

Loss of excitation can, to some extent, be sensed within the excitation system itself by

monitoring for loss of field voltage or current. For generators that are paralleled to a power system, the preferred method is to monitor for loss of field at the generator terminals. When a generator loses excitation power, it appears to the system as an inductive load, and the machine begins to absorb a large amount of VARs. Loss of field may be detected by monitoring for VAR flow or apparent impedance at the generator terminals.

The power diagram (P-Q plane) of Fig. 18 shows the Basler BE1-GPS100 and BE1-40Q characteristic with a representative setting, a representative generator thermal capability curve, and an example of the trajectory following a loss of excitation. The first quadrant of the diagram applies for lagging power factor operation (generator supplies VARs). The trajectory starts at point A and moves into the leading power factor zone (4th quadrant) and can readily exceed the thermal capability of the unit. A trip delay of about 0.2-0.3 seconds is recommended to prevent unwanted operation due to other transient conditions. A second high speed trip zone might be included for severe underexcitation conditions.

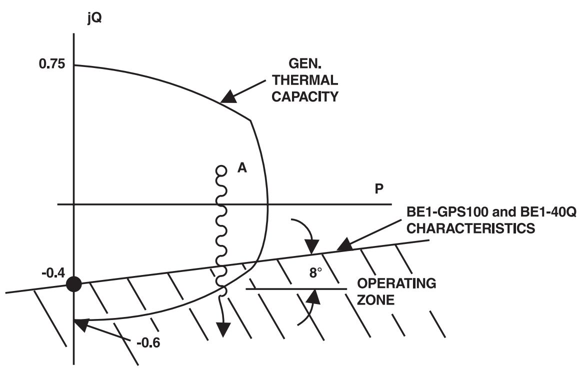


FIGURE 18. FOR LOSS OF FIELD THE POWER TRAJECTORY MOVES FROM POINT A INTO THE FOURTH QUADRANT.

When impedance relaying is used to sense loss of excitation, the trip zone typically is marked by a mho circle centered about the X axis, offset from the R axis by X'd/2. Two zones sometimes are used: a high speed zone and a time delayed zone.

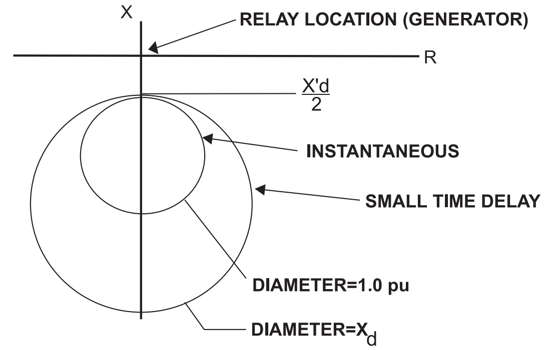


FIG. 19. LOSS OF EXCITATION USING IMPEDANCE RELAY.

With complete loss of excitation, the unit will eventually operate as an induction generator with a positive slip. Because the unit is running above synchronous speed, excessive currents can flow in the rotor, resulting in overheating of elements not designed for such conditions. This heating cannot be detected by thermal relay 49, which is used to detect stator overloads.

Rotor thermal capability can also be exceeded for a partial reduction in excitation due to an operator error or regulator malfunction. If a unit is initially generating reactive power and then draws reactive power upon loss of excitation, the reactive swings can significantly depress the voltage. In addition, the voltage will oscillate and adversely impact sensitive loads. If the unit is large compared to the external reactive sources, system instability can result.

Thermal Protection

Fig. 20 shows the Basler MPS200, BE3-49R, or BE1-49 relay connected to a resistance-temperature detector, embedded in a stator slot. Relay models are available for either copper or platinum RTDs. The relay provides a constant-current source to produce a voltage across the RTD and includes the means to measure that voltage (proportional to temperature) using separate leads. The relays have trip and alarm set points, and the MPS200 can provide readout of present temperature.

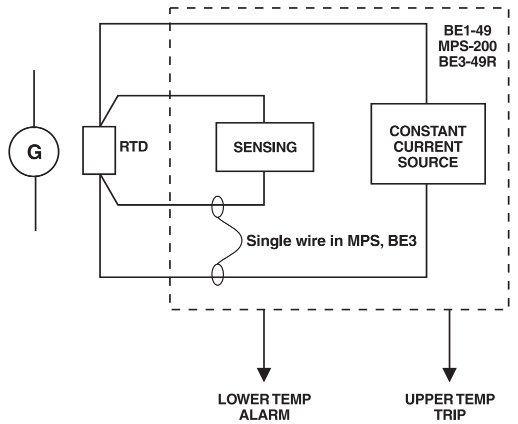


FIGURE 20. STATOR TEMPERATURE PROTECTION.

Loss of VT Detection

Two methods in common use to detect loss of VTs are voltage balance between two VTs and voltage-current comparison logic. Fig. 21 shows the use of two sets of VTs on the generator terminals, with the 60FL (Basler BE1-60) comparing the output of the two VTs. One set supplies the voltage regulator, the other, the relays. If the potential decreases or is lost from VT No. 1, the BE1-60 disables the voltage regulator; if source No. 2 fails, the BE1-60 blocks relay tripping of the 21, 27, 59N, and 47. In some applications 25, 32, and 40 elements are also blocked. Overexcitation relay (24), phase overvoltage (59), and frequency relaying (81), do not need to be blocked, since loss of potential leads toward non-operation of these functions.

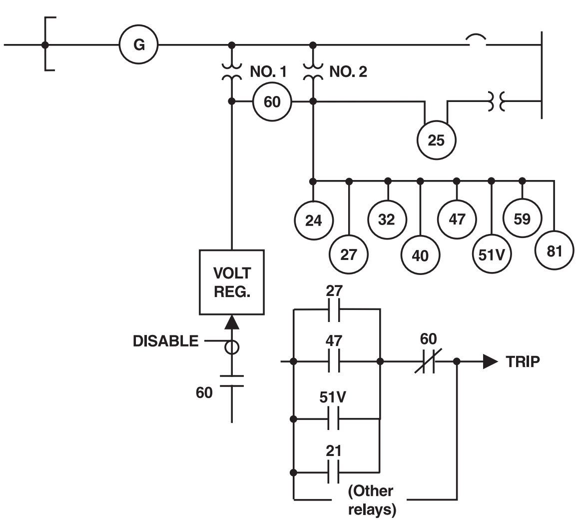


FIGURE 21. VARIOUS VOLTAGE PROTECTION ELEMENTS. VOLTAGE-BALANCE RELAY (60) DETECTS POTENTIAL SUPPLY FAILURE.

A second means of detecting fuse loss is by comparing voltage and current (Fig. 22). In a single phase or two phase fuse loss, voltage imbalance exists without the corresponding current imbalance that would exist during a fault. In a three phase fuse loss, complete voltage loss occurs without the corresponding three phase current flow that would occur during a fault. To prevent a 60FL from being declared during loss of station power, it may be necessary to allow a 3 phase 60F to be declared only when some low level of load current exists.

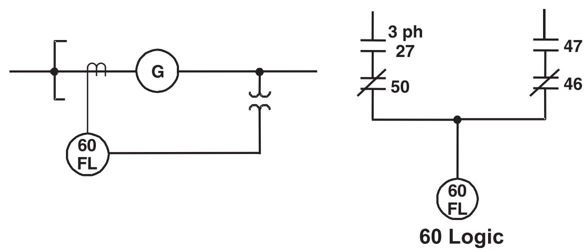


FIGURE 22. LOSS OF FUSE DETECTION, ALTERNATE METHOD.

Overexcitation and Over/Under Voltage Protection

Overexcitation can occur due to higher than rated voltage, or rated or lower voltage at less than rated frequency. For a given flux level, the voltage output of a machine will be proportional to frequency. Since maximum flux level is designed for normal frequency and voltage, when a machine is at reduced speed, maximum voltage is proportionately reduced. A volts/hertz relay (24) responds to excitation level as it affects thermal stress to the generator (and to any transformer tied to that generator). IEEE C50.13 specifies that a generator should continuously withstand 105% of rated excitation at full load.

With the unit off line, and with voltage-regulator control at reduced frequency, the generator can be overexcited if the regulator does not include an overexcitation limiter. Overexcitation can also occur, particularly with the unit off line, if the regulator is out of service or defective. If voltage-balance supervision (60) is not provided and a fuse blows on the regulator ac potential input, the regulator would cause overexcitation. Loss of ac potential may also fool the operator into developing excessive excitation. The 24 relay can only

protect for overexcitation resulting from an erroneous voltage indication if the 24 relay is connected to an ac potential source different than that used for the regulator.

Fig. 23 shows the relation among the Basler BE1-GPS100, BE1-951, BE1051, and BE1-24 relay inverse squared characteristics and an example of a generator and transformer withstand capability. The generator and transformer manufacturers should supply the specific capabilities of these units.

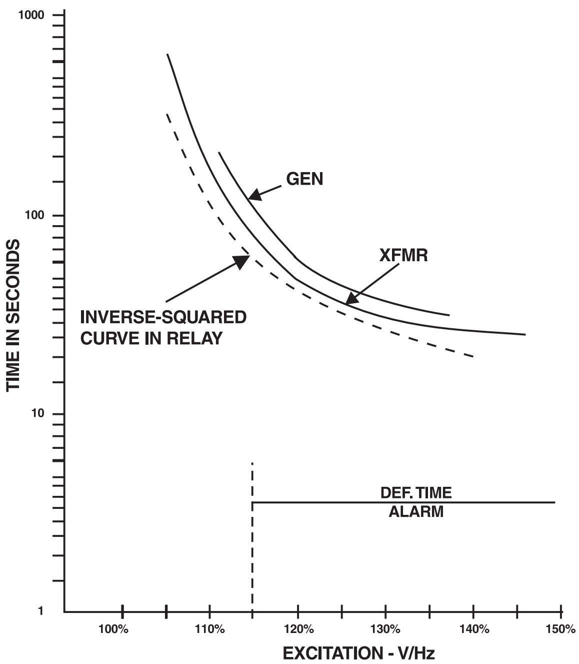


FIGURE 23. COMBINED GENERATOR/TRANSFORMER OVEREXCITATION PROTECTION USING BOTH THE INVERSE SQUARED TRIPPING. EQUIPMENT WITHSTAND CURVES ARE EXAMPLES ONLY.

Phase over (59) and under (27) voltage relaying also acts as a backup for excitation system problems. Undervoltage relaying also acts as fault detection relaying, because faults tend to depress voltage.

Off-Frequency Operation

Diesel engines can be safely operated off normal frequency, and minimal protection is required. Turbine controls generally provide protection for off frequency conditions, but relaying should be provided to protect the turbine and generator during control system failure. Frequency relays are frequently applied with steam-turbine units, particularly to minimize turbine blade fatiguing. IEEE C37.106, Ref. 3 specifically addresses abnormal frequency operation and shows typical frequency operating limits specified by various generator manufacturers. The simplest relay application would be a single underfrequency stage, but a multiple stage and multiple set point arrangement may be advantageous. Each set point may be set to recognize either over-frequency or underfrequency. Multiple frequency set points are available in the BE1-81O/U, BE1-GPS100, BE1-951, and BE1-1051.

Another common need for frequency relaying is the detection of generation that has become isolated from the larger utility system grid. When a generator is connected to the utility, generator frequency is held tightly to system frequency. Upon islanding, the generator frequency varies considerably as the governor works to adjust generator power output to local load. If the generator frequency varies from nominal, islanding is declared and either the generator is tripped or the point of common coupling with the utility is opened.

Inadvertent Energization Protection

Inadvertent energization can result from a breaker interrupter flashover or a breaker close initiation while the unit is at standstill or at low speed. The rapid acceleration can do extensive damage, particularly if the generator is not promptly de-energized. While relays applied for other purposes may eventually respond, they are not generally considered dependable for responding to such an energization.

Figs. 24 and 25 show two methods of detecting the energization of a machine at standstill or at a speed significantly lower than rated. This could be caused by single-phase energization due to breaker-interrupter flashover or 3 phase energization due to breaker closure. The unit, without excitation, will accelerate as an induction motor with excessive current flow in the rotor. Both Fig. 24 and 25 schemes will function properly with the VT fuses at the generator terminal removed. With the generator off line, safety requirements may dictate the removal of these VT fuses. In the case of Fig.

24, the overcurrent protection is enabled by undervoltage units and works as long as 60FL logic does not block the trip path. In Fig. 25 the potential is taken from bus VTs, rather than unit VTs, so the scheme will function even if the VT fuses were removed during unit maintenance.

In Fig. 24 the terminal voltage will be zero prior to energization, so the 27 and 81U relay contacts will be closed to energize the timer (62). The instantaneous overcurrent relay (50) trip circuit is established after timer 62 operates. Upon inadvertent generator energization, the undervoltage and underfrequency relay contacts may open up due to the sudden application of nominal voltage and frequency, but the delayed dropout of 62 allows relay 50 to initiate tripping. The use of a 60FL function or two 27 relays on separate VT circuits avoids tripping for a VT fuse failure. Alternatively, a fuse loss detection or voltage-balance relay (60FL) could be used in conjunction with a single 27 relay to block tripping.

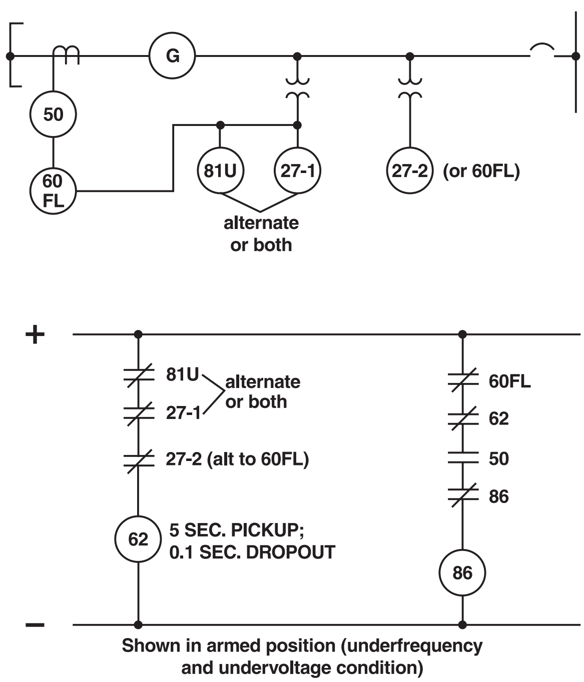


FIGURE 24. INADVERTENT ENERGIZATION PROTECTION USING INSTANTANEOUS OVERCURRENT RELAY (50).

In Fig. 24 the 5 sec pickup delay on timer 62 prevents tripping for external disturbances that allow dropout of the 27 relays. The 27 relays should be set at 85% voltage (below the operating level under emergency conditions). The Fig. 25 scheme could be employed where protection independent of the plant is desired. In this case the 67 relays would be placed in the switchyard rather than in the control room. While directional overcurrent relay (67) should be delayed to ride through synchronizing surges, it can still provide fast tripping for generator faults, since the 67 relays need not be coordinated with external protection. Fig. 25 shows the operating range for phase A current (Ia) with respect to phase B to C voltage (V_{BC}). This range is fixed by the 60 degree characteristic angle and the ±45 degree limits set on the operating zone.

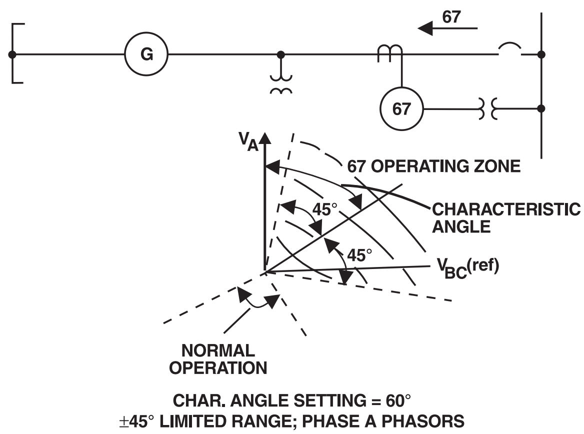


FIGURE 25. BE1-67 DIRECTIONAL OVERCURRENT RELAYS DETECT INADVERTENT ENERGIZATION.

Negative Sequence Protection

Negative sequence stator currents, caused by fault or load unbalance, induce double-frequency currents into the rotor that may eventually overheat elements not designed to be subjected to such currents. Series unbalances, such as untransposed transmission lines, produce some negative-sequence current (I_2) flow. The most serious series unbalance is an open phase, such as an open breaker pole. ANSI C50.13-1977 specifies a continuous I_2 withstand of 5 to 10% of rated current, depending upon the size and design of the generator. These values can be exceeded with an open phase on a heavily-loaded generator. The Basler BE1-GPS100, BE1-951, BE1-1051, or BE1-46N relay protects against this condition, providing negative sequence inverse-time protection shaped to match the short-time withstand capability of the generator should a protracted

fault occur. This is an unlikely event, because other fault sensing relaying tends to clear faults faster, even if primary protection fails.

Fig. 26 shows the 46 relay connection. CTs on either side of the generator can be used, since the relay protects for events external to the generator. The Basler BE1-46N alarm unit will alert the operator to the existence of a dangerous condition.

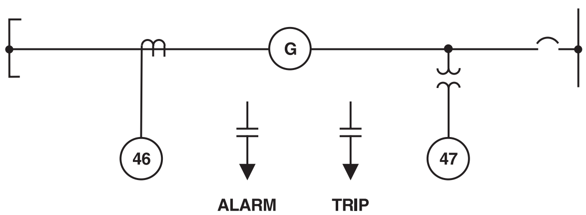


FIGURE 26. NEGATIVE-SEQUENCE CURRENT RELAY (46) PROTECTS AGAINST ROTOR OVERHEATING DUE TO A SERIES UNBALANCE OR PROTRACTED EXTERNAL FAULT. NEGATIVE SEQUENCE VOLTAGE RELAY (47) (LESS COMMONLY APPLIED) ALSO RESPONDS.

Negative sequence voltage (47) protection, while not as commonly used, is an available means to sense system imbalance as well as, in some situations, a misconnection of the generator to a system to which it is being paralleled.

Out of Step Protection

When a generator pulls out of synchronism with the system, current will rise relatively slowly compared to the instantaneous change in current associated with a fault. The out-of-step relay uses impedance techniques to sense this condition. The relay will see an apparent load impedance swing as impedance moves from Zone 1 to Zone 2 (Fig. 27). The time it takes for the load impedance to traverse from Zone 1 to Zone 2 is used to decide if an out of step

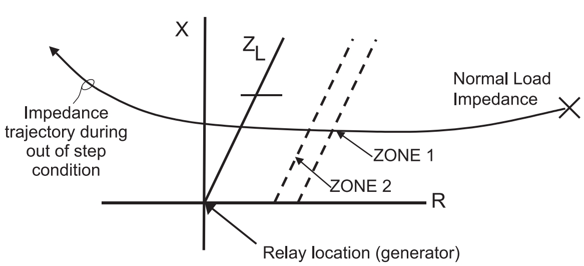


FIGURE 27. OUT OF STEP RELAYING (78)

condition is occurring. A moving impedance is identified as a swing rather than a fault, so appropriate fault detection relaying may be blocked.

Selective Tripping and Sequential Tripping

It is a practice at some generators to selectively trip the prime mover, the field, and the generator breaker, depending on the type of fault that is detected. For instance, if the generator is protected by a 51V and an 87G, and only the 51V trips, it may be assumed that the fault is external to the generator and, hence, the 51V only trips the generator breaker and rapidly pulls back the excitation governor and prime mover set points. However, if there is no 87G, the 51V trips the entire unit. Associated with this concept is sequential tripping used for orderly shutdown. To prevent overspeeding a generator during shutdown, it is sometimes the practice first to trip the prime mover and trip the main breaker and field only after a reverse power relay verifies the prime mover has stopped providing torque to the generator.

Synchronism Check and Auto Synchronizing

Before connecting a generator to the power system, it is important that the generator and system frequency, voltage magnitude, and phase angle be in alignment, referred to as synchronism checking (25). Typical parameters are shown in Fig. 28. Typical applications call for no more than 6RPM error, 2% voltage magnitude difference, and no more than 10° phase angle error before closing the breaker. The Basler BE1-951, BE1-GPS, and BE1-25 all can perform the sync check function.

Auto synchronizing (25A) refers to a system to automatically bring a generator into synchronism with the power system. It involves sending voltage and speed raise and lower commands to the voltage regulator and prime mover governor. When the system is in synchronism, the autosync relay is sometimes designed to send a close command in advance of the zero phase angle error point to compensate for breaker close delays. The 25 relay, which usually is set to supervise the 25A and manual sync function, usually is set less tight than the 25A so as to coordinate with the actions of the 25A.

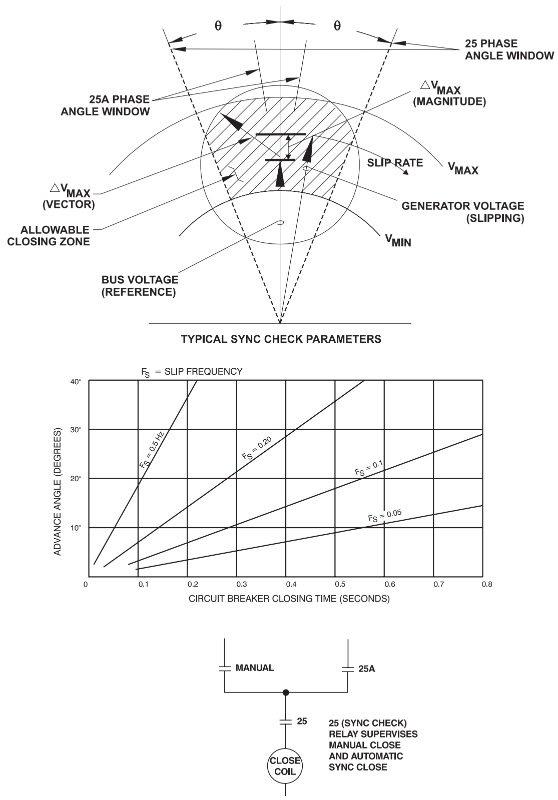


FIGURE 28. SYNCHRONIZING PARAMETERS: SLIP, ADVANCE ANGLE, AND BREAKER CLOSING TIME.

Integrated Application Examples

Figs. 29 through 33 show examples of protection packages.

Fig. 29 represents bare-minimum protection, with only overcurrent protection. Generators with such minimum protection are uncommon in an era of microprocessor-based multifunction relays. Such protection likely would be seen only on very small (<50kVA) generators used for standby power that is never paralleled with the utility grid or other generators. It may appear to be a disadvantage to use CTs on the neutral side as shown, since the relays may operate faster with CTs on the terminal side. The increase in speed would be the result of a larger current contribution from external sources. However, if the CTs are located on the terminal side of the generator, there will be no protection prior to putting the machine on line. This is not recommended, because a generator with an internal fault could be destroyed when the field is applied.

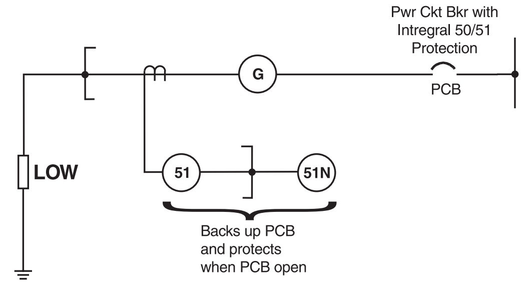


FIGURE 29. EXAMPLE OF BARE-MINIMUM PROTECTION (LOW-IMPEDANCE GROUNDING).

Fig. 30 shows the suggested minimum protection with low-resistance grounding. It includes differential protection, which provides fast, selective response, but differential protection becomes less common as generator size decreases below 2MVA, on 480V units and below, and on generators that are never paralleled with other generation. The differential relay responds to fault contributions from both the generator and the external system. While the differential relay is fast, the slow decay of the generator field will cause the generator to continue feeding current into a fault. However, fast relay operation will interrupt the external-source contribution, which may be greater than the generator contribution. Fast disconnection from the external source allows prompt restoration of normal voltage to loads and may reduce damage and cost of repairs.

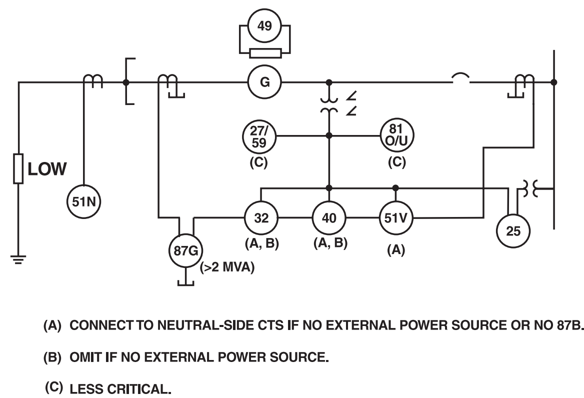


FIGURE 30. SUGGESTED MINIMUM PROTECTION EXAMPLE (LOW-IMPEDANCE GROUNDING).

The differential relay (87G) may protect for ground faults, depending upon the grounding impedance. The 51N relay in Fig. 30 provides back-up protection for the 87G or will be the primary protection if the differential relay (87G) is

not sufficiently sensitive to the ground current level.

The 51V voltage-controlled or voltage-restrained time overcurrent relay in Fig. 30 is shown on the CT on the high voltage/system side of the generator. This allows the relay to see system contributions to a generator fault. It provides back-up for the differential relay (87G) and for external relays and breakers. Since it is monitoring CTs on the system side of the generator, it will not provide any back-up coverage prior to having the unit on line. If there is no external source, no 87G, or if it is desired that the 51V provide generator protection while the breaker is open, connect the 51V to the neutral-side CTs.

Fig. 30 shows three relays sharing the same CTs with a differential relay. This is practical with solid state and numeric relays, because their low burden will not significantly degrade the quality of differential relay protection. The common CT is not a likely point of failure of all connected relaying. A CT wiring error or CT short is unlikely to disable both the 87G and 51V relays. Rather, a shorted CT or defective connection will unbalance the differential circuit and cause the 87G to trip. Independent CTs could be used to provide improved back-up protection, although this seems to be a minimal advantage here. However, a separate CT is used for the 51N relay that provides protection for the most likely type of fault.

The reverse power relay (32) in Fig. 30 protects the prime mover against forces from a motored generator and could provide important protection for the external system if the motoring power significantly reduces voltage or overloads equipment. Likewise, the loss-of-field relay (40) has dual protection benefits—against rotor overheating and against depressed system voltage due to excessive generator reactive absorption. Thermal relay (49) protects against stator overheating due to protracted heavy reactive power demands and loss of generator cooling. Even if the excitation system is equipped with a maximum excitation limiter, a failure of the voltage regulator or a faulty manual control could cause excessive reactive power output. Frequency relaying (81O/U) protects the generator from off nominal frequency operation and senses generator islanding. The under and overvoltage function (27/59) detects excitation system problems and some protracted fault conditions.

Fig. 31 shows minimum basic protection for a medium impedance grounded generator. It differs from Fig. 30 only in the use of a ground differential relay (87N, part of CDS220 or BE1-67N). This protection provides faster clearing of ground faults where the grounding impedance is too high to sense ground faults with the phase differential relay (87G). The relay compares ground current seen at the generator high voltage terminals to ground current at the generator neutral. The 51N relay provides backup for the ground differential (87N) and for external faults, using the current polarizing mode. The polarizing winding measures the neutral current.

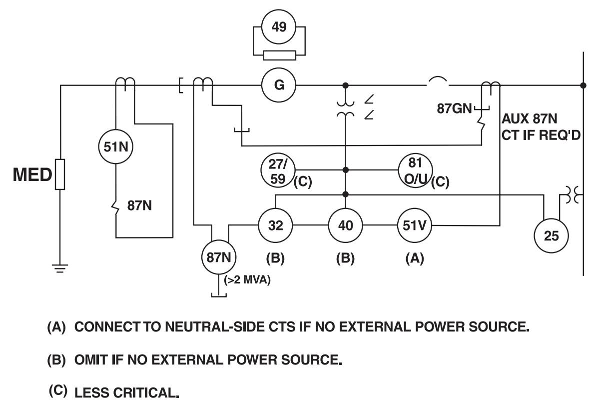
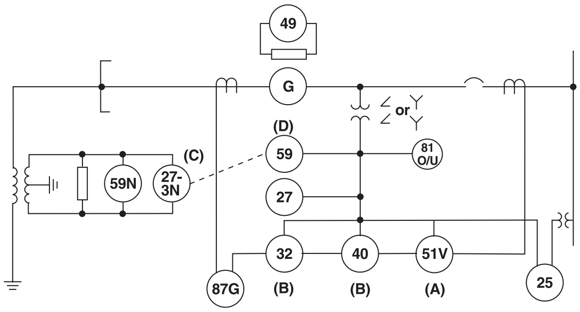


FIGURE 31. SUGGESTED MINIMUM PROTECTION EXAMPLE (MEDIUM-IMPEDANCE GROUNDED).

Fig. 32 shows minimum basic protection for a high impedance grounded generator. It differs from Fig. 30 only in the ground relay protection and the method of grounding. The voltage units 59N/27-3N provide the only ground protection, since the ground fault current is too small for phase differential relay (87G) operation. The 59N relay will not be selective if other generators are in parallel, since all the 59N relays will see a ground fault and nominally operate at the same time. If three Phase-Ground Y-Y VTs were applied in Fig. 32, the 27 and 59 could provide additional ground fault protection, and an additional generator terminal 59N ground shift relay could be applied.



(A) CONNECT TO NEUTRAL-SIDE CTS IF NO EXTERNAL POWER SOURCE.

(B) OMIT IF EXTERNAL POWER SOURCE.

(C) INCLUDED IN BE1-59N RELAY.

(D) SUPERVISES 27-3N TRIP.

FIGURE 32. SUGGESTED MINIMUM PROTECTION EXAMPLE (HIGH-RESISTANCE GROUNDING).

The Basler BE1-951, BE1-1051, BE1-GPS100, and BE1-59N include a third harmonic undervoltage function (27-3N), that provides supervision of the grounding system, protects for faults near the generator neutral, and detects a shorted or open connection in the generator ground connection or in the distribution transformer secondary circuit.

Fig. 33 shows the application of additional relays for extended protection: overexcitation relay (24), negative sequence overcurrent and overvoltage relay (46 and 47), ground-overcurrent relay (51GN), voltage-balance relay (60), field-ground relay (64F), frequency relay (81) and the 27/50/62 relay combination for inadvertent energization protection. Relay 51GN provides a second means of detecting stator ground faults or faults in the generator connections or faults in the delta transformer windings. Differential relay 87T and sudden-pressure relay 63 protect the unit step-up transformer. Relay 51N provides backup for external ground faults and for faults in the high-voltage transformer windings and leads. This relay may also respond to an open phase condition or a breaker-interrupter flashover that energizes the generator. The 51N relay will be very slow for the flashover case, since it must be set to coordinate with external relays and is a last-resort backup for external faults.

Figure 33 shows wye-connected VTs, appropriate with an isolated-phase bus.

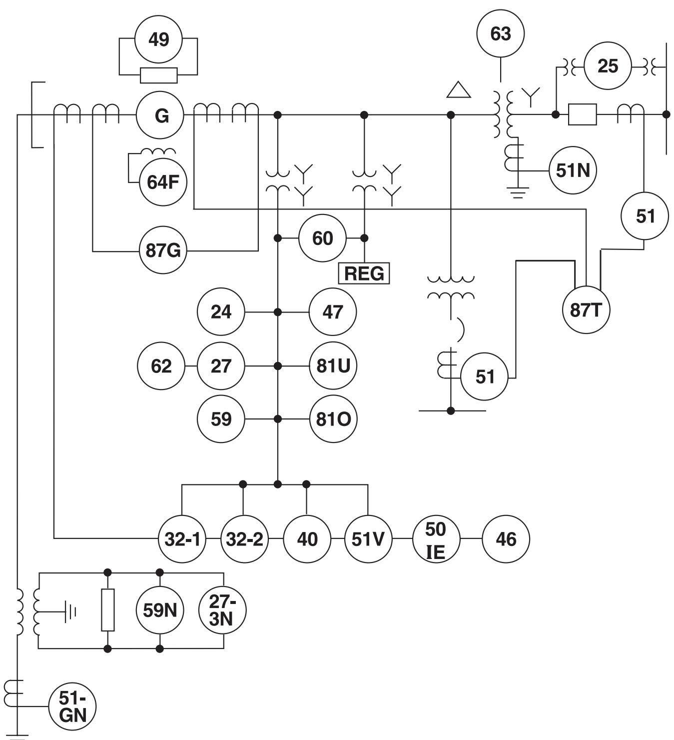


FIGURE 33. EXTENDED PROTECTION EXAMPLE (HIGH-RESISTANCE GROUNDING).

Application of Numerical Programmable Relays

Numerical programmable relays contain many of the functions discussed in this guideline in a single package. Figures 34 through 37 show the BE1-GPS100 and BE1-CDS220 applied to generator protection. Due to logic complexity, full details are not shown. Details of these applications may be found in the respective instruction manual.

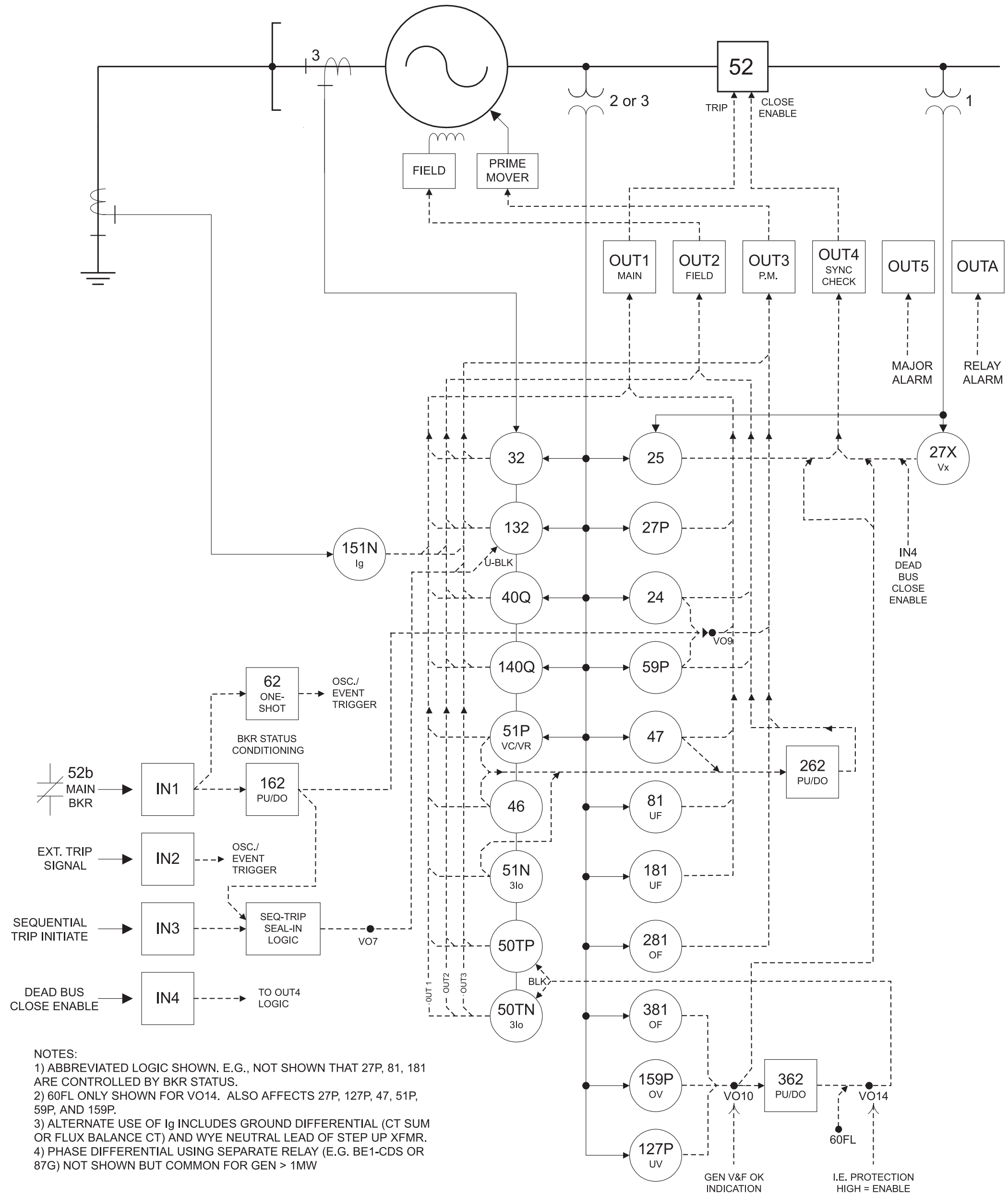
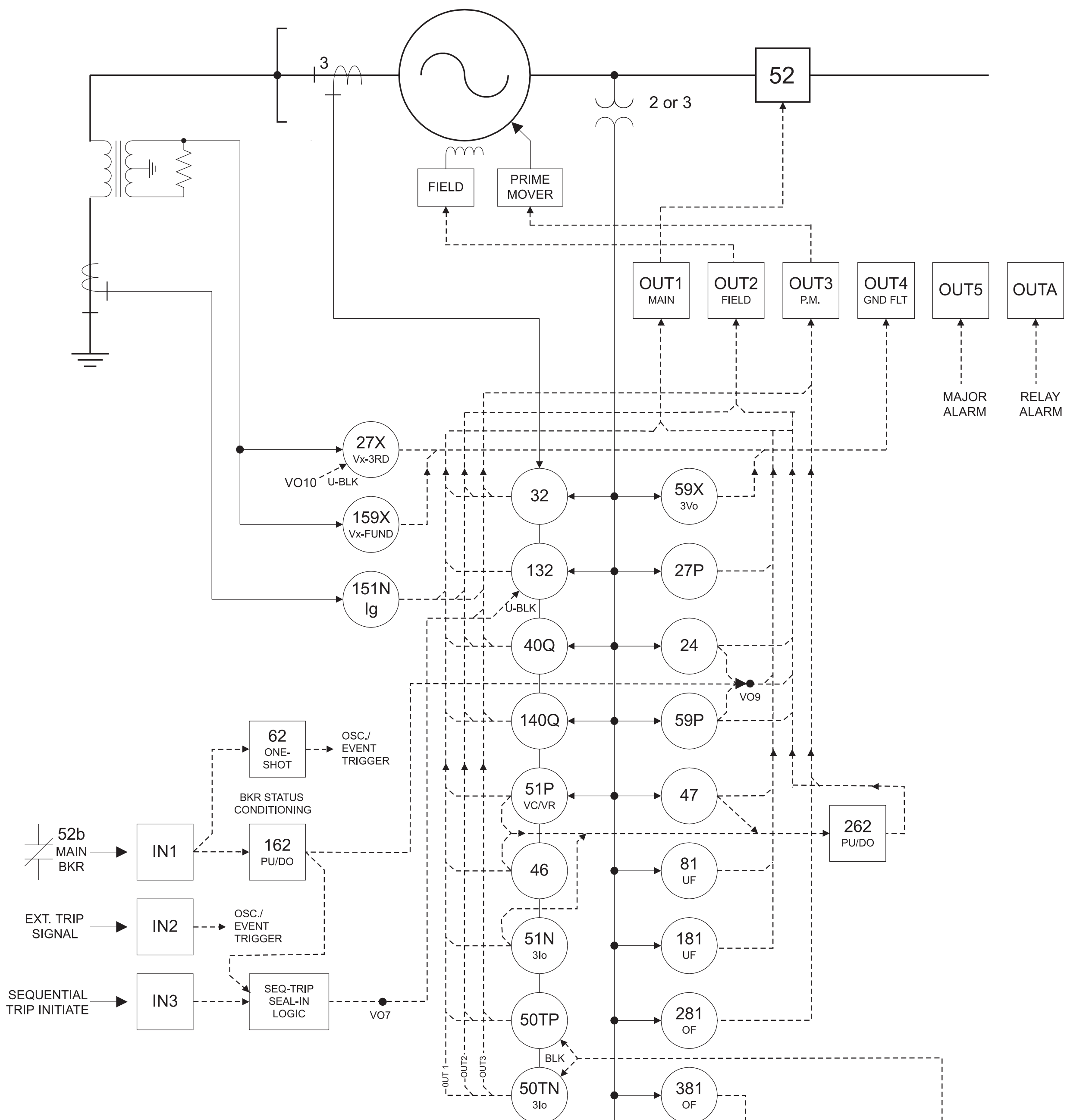


FIGURE 34. BE1-GPS100 APPLIED TO LOW-IMPEDANCE GROUNDED GENERATOR (LOW-Z-W25 PREPROGRAMMED LOGIC; SEE INSTRUCTION MANUAL FOR LOGIC DETAILS).



NOTES:
1) ABBREVIATED LOGIC SHOWN. E.G., NOT SHOWN THAT 27P, 81, 181 ARE CONTROLLED BY BKR STATUS.
2) 60FL ONLY SHOWN FOR VO14. ALSO AFFECTS 27P, 127P, 47, 51P, 59P, AND 159P.
3) ALTERNATE USE OF Ig INCLUDES GROUND DIFFERENTIAL (CT SUM OR FLUX BALANCE CT) AND WYE NEUTRAL LEAD OF STEP UP XFMR.
4) PHASE DIFFERENTIAL USING SEPARATE RELAY (E.G. BE1-CDS OR 87G) NOT SHOWN BUT COMMON FOR GEN > 1MW.

FIGURE 35. BE1-GPS100 APPLIED TO HIGH-IMPEDANCE GROUNDED GENERATOR (HI_Z_GND PREPROGRAMMED LOGIC; SEE INSTRUCTION MANUAL FOR LOGIC DETAILS).

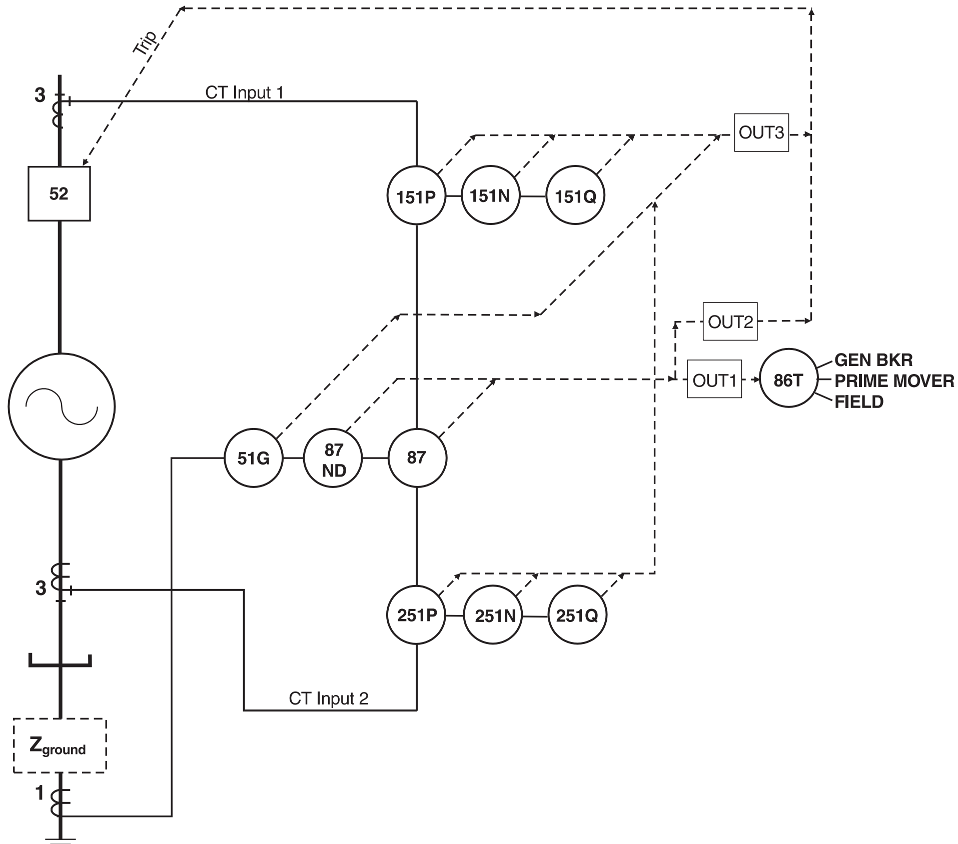


FIGURE 36. BE1-CDS220 APPLIED TO GENERATOR FOR 87 PHASE, 87 NEUTRAL, AND 51 PHASE, NEUTRAL, GROUND, AND NEGATIVE SEQUENCE.

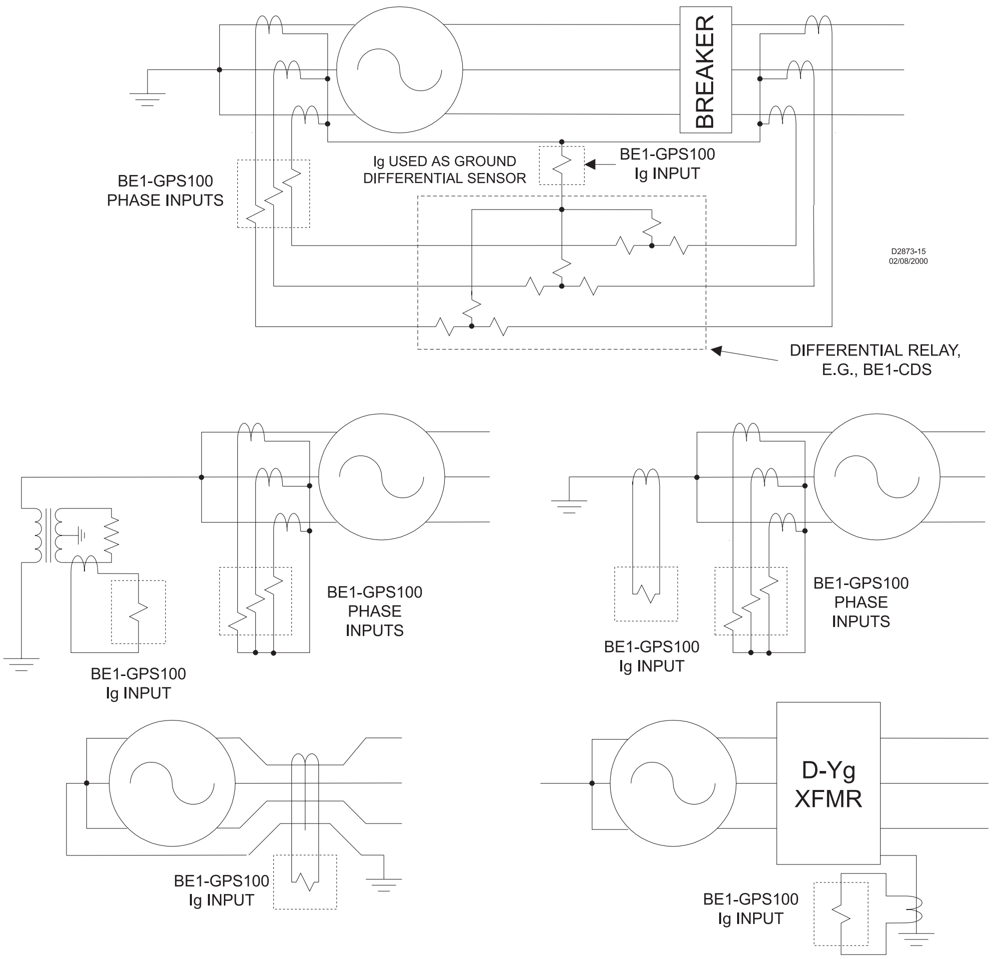


FIGURE 37. INTERCONNECTION OF BE1-GPS100 AND BE1-CDS220, AND SHOWING SOME ALTERNATE USES OF BE1-GPS100 I_G INPUT.

Bibliography

1. IEEE C37.101, IEEE Guide for Generator Ground Protection
2. IEEE C37.102, IEEE Guide for AC Generator Protection
3. IEEE C37.106, IEEE Guide for Abnormal Frequency Protection for Generating Plants
4. J. Lewis Blackburn, “Protective Relaying: Principles and Applications”, 2nd Edition, Marcel Dekker, Inc., 1998.
5. S. Horowitz and A. Phadke, “Power System Relaying”, John Wiley & Sons, Inc., 1992.

Typical Settings and Relays

Table 1 lists the applicable relays discussed herein. The right column provides typical settings for use as a starting point in the setting determination procedure. The proper settings are heavily influenced by the specifics of each application. Typical settings are also used as an aid in selecting the relay range where a choice is available.

Table 2 lists typical Basler relays applicable to generator protection. There are 3 classes of relays presented in Table 2. The classical single function "utility grade" (i.e., tested to IEEE C37.90 standards) BE1-XXX relays are listed, followed by the single function "industrial grade" BE3-XXX relays. (Except the multifunction BE3-GPR is tested to full IEEE C37.90 standards.) Finally, the multifunction utility grade numerical relays are listed. Additional information on each relay is available on the Basler Electric web site, www.basler.com.

Table 1 - Typical Settings

IEEE No.	Fig.	Function	Typical Settings and Remarks
24	21, 23	Overexcitation	PU: 1.1*V_{NOM}/60; TD: 0.3; reset TD: 5 alarm P.U.: 1.18*V_{NOM}/60 alarm delay: 2.5s
25	21, 28	Synchronism Check	Max Slip: 6RPM; Max phase angle error: 10° Max V_{MAG} error: 2.5% V_{NOM}
32	16, 17	Reverse Power (one stage)	PU: turbine 1% of rated; 15 s PU: Reciprocating engine: 10% of rated; 5 s
32-1	17	Reverse Power Nonelectrical Trip Supervision	PU: same as 32; 3 s
40	16, 18	Loss-of-field (VAR Flow Approach)	Level 1 PU: 60% VA rating; Delay: 0.2s; Level 2 PU: 100% VA rating: 0.1s
46	26	Negative Sequence Overcurrent	I_2 PU: 10% I_{rated}; K=10
49	20	Stator Temperature (RTD)	Lower: 95°C; upper: 105°C
50/87	12	Differential via flux summation CTs	PU:10% I_{NOM} or less if 1A relay may be used
50/27 IE	24	Inadvertent Energization Overcurrent with 27, 81 Supervision	50: 0.5A (10% I_{NOM}) 27: 85% V_{NOM} (81: Similar)
51N	3	Stator Ground Over-current (Low, Med Z Gnd, Phase CT Residual)	PU: 10% I_{NOM}; curve: EI; TD: 4. Inst: none. Higher PU required to coordinate with load. No higher than 25% I_{NOM}.
50/51N	2	Stator Ground Over-current (Low, Med Z Gnd, Neutral CT or Flux Summation CT)	P.U.: 10% I_{NOM}; Curve EI, TD4; Inst 100% I_{NOM}. Higher PU if required to coordinate with load. No higher than 25% I_{NOM}.
51GN, 51N	4, 7	Stator Ground Over-current (High Z Gnd)	PU: 10% I_{FAULT} at HV Term.; Curve: VI; TD:4.
51VC	11	Voltage Controlled Overcurrent	PU: 50% I_{NOM}; Curve: VI; TD: 4. Control voltage: 80%V_{NOM}.

Table 1 - Typical Settings

IEEE No.	Fig.	Function	Typical Settings and Remarks
51VR	11	Voltage Restrained Overcurrent	PU: 175% I_{NOM}; Curve: VI; TD: 4. Zero Restraint Voltage: 100% $V_{NOM\ L\text{-}L}$
59N, 27-3N, 59P	4	Ground Overvoltage	59N: 5% V_{NEU} during HV terminal fault; 27-3N: 25% V_{3rd} during normal operation; TD: 10s 59P: 80% V_{NOM}
67IE	25	Directional O/C for Inadvertent Energization	PU: 75-100% $I_{NOM\ GEN}$; Definite Time (0.1-0.25 sec.) Inst: 200% $I_{NOM\ GEN}$
81	21	Over/under frequency	Generator protection: 57, 62Hz, 0.5s; Island detection: 59, 61Hz, 0.1s
87G	13	Generator Phase Differential	BE1-87G: 0.4A; BE1-CDS220: Min P.U.: 0.1 * Tap; Tap: I_{NOM}; Slope: 15%
87N	8	Generator Ground Differential	BE1-CDS220: Min P.U.: 0.1 times tap; Slope 15%; Time delay: 0.1s; choose low tap BE1-67N: current polarization; time: 0.25A; Curve: VI; TD: 2; Instantaneous: disconnect
87UD	13	Unit Differential	BE1-87T or CDS220 Min PU:0.35*Tap; Tap: I_{NOM}; Slope 30%

Table 2 - Basler Electric Relay Application Matrix

IEEE Number	Single Function BE1-	Single Function BE3-	Multifunction (3) X=Included ◊=Optional							
			BE1-851	BE1-951	BE1-1051	BE1-GPS	BE1-CDS	BE3-GPR 50TN	BE3-GPR 51 Ph	MPS200
24	24			X	X	X				
25	25	25		◊	◊	◊		◊	◊	
25A	25A	25A								
27	27	27		X	X	X		X	X	X
27/50IE	50/51B, 50, 27	27, 51		X	X	X				
27/59	27/59	27/59		X	X	X		X	X	
32	32R, 32O/U	32		X	X	X		◊	◊	X
40	40Q					X		◊	◊	
46	46N		X	X	X	X	X			X
47	47N	47N		X	X	X		◊	◊	X
49	49	49R, 49TH								X
49/51										
50/51G (1)	50/51B, 51	51	X	◊	◊	◊	◊	50T		X
50/51N (2)				X	X	X	X			
50/87	50/51B, 50	51	X	X	X	X	X			
51P	50/51B, 51	51	X	X	X	X	X			
51VC	51/27C			X	X	X				
51VR	51/27R			X	X	X			X	
59P	59	59		X	X	X		X	X	X
59N, 27-3N, 59P	59N			◊ (4)	◊ (4)	◊ (4)				
60FL	60			X	X	X				
67IE	67			X	X					
81	81O/U	81O/U		X	X	X		X	X	
87G	87G						X			
87N	67N				◊		◊			
87UD	87T						X			

(1) 50/51G - Indicates a relay that monitors a ground CT source.
(2) 50/51N - Indicates a relay that calculates residual ($3I_0$) from phase currents.
(3) Not all functions in relays are shown. Relays also may include multiple set points and setting groups.
(4) BE1-951, -1051, and -GPS have standard capability to calculate $3V_0$ from wye-connected phase CTs. V_{AUX} input is optional.

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If you have any questions or need additional information, please contact **Basler Electric Company**.
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